STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2002-483

October 22, 2002

NORTHERN UTILITIES, INC. – MAINE
Proposed Cost of Gas Factor
November 2002 through April 2003

ORDER

WELCH, Chairman; NUGENT and DIAMOND, Commissioners

I. SUMMARY

We direct Northern Utilities, Inc. to file revised Cost of Gas Factor (CGF) rates in accordance with the enclosed determinations by Friday, October 25, 2002. We approve revised rates to take effect November 1, 2002, for the upcoming winter period subject to compliance review and approval by the Director of Technical Analysis.

II. PROCEDURAL HISTORY

On August 15, 2002, pursuant to 35-A M.R.S.A. § 4703 and Chapter 430(2) of the Commission's Rules, Northern filed its proposed CGF for the Winter 2002 - 2003 gas usage period, as well as its proposed change to the Environmental Recovery Cost Adjustment (ERCA) as allowed in Docket No. 96-678. The Commission issued a Notice of Application to interveners in prior CGF cases and by publication in newspapers of general circulation in Northern's service area. As initially filed, Northern's proposed 2002-2003 Winter CGF would result in a 4.75% increase for its highest usage residential customers.

On August 23, 2002, the Office of the Public Advocate (OPA) intervened. To investigate the proposed CGF changes, the Advisory Staff issued data requests to the Company on its filing. A preliminary hearing and technical conference was held on September 24, 2002 at which the Advisory Staff and OPA explored the issues raised by this filing. On September 27, 2002, the Hearing Examiner issued a procedural order setting the remaining schedule in this case.

III. RECORD

The record in this proceeding includes all filings, data responses, transcripts, and any other materials provided in this proceeding.

IV. DISCUSSION AND RECOMMENDATIONS

A. Overview of Proposed Rates

Northern initially proposed the following 2002 - 2003 Winter Period CGF rates on a per hundred cubic feet (Ccf) basis in its August 15, 2002 filing to become effective November 1, 2002:

Class	Rate
Residential - Heat & Non-Heat (R-2 & R-1)	$0.8352
Small Commercial - Low Winter Use (G-50)	0.6840
Small Commercial - High Winter Use (G-40)	0.8564
Medium Commercial - Low Winter Use (G-51)	0.6840
Medium Commercial - High Winter Use (G-41)	0.8564
Large Commercial/Industrial – Low Winter Use (G-52)	0.6840
Large Commercial/Industrial – High Winter Use (G-42)	0.8564

The original filing also includes an ERCA of $0.0062 for the 2002 – 2003 winter period that reflects the costs incurred during the period July 2001 to June 2002 in accordance with the settlement in Docket No. 96-678.

The issues related to these proposed rates are discussed separately below.

B. Issues

1. Futures Prices

Northern calculates its commodity costs using estimates based upon the closing prices of NYMEX natural gas futures contract. Subsequent futures gas prices have closed significantly higher than the futures prices that Northern used to make its current filing although these prices can be expected to fluctuate.[1] In order to send appropriate price signals to Northern's customers, the Commission has allowed Northern to update it's filing based upon the most current futures available when it makes its final updated filing. Consistent with this practice, Northern should calculate its updated cost of gas factor utilizing futures prices that reflect the most current market conditions in its revised filing.

2. Last Winter Period Under-collection

Northern reported an under-collection from the last winter period of approximately $1,238,216 of which $703,864 was related to demand and $534,352 was

[1] For example, while the futures settlement prices per MMBTU on September 23, 2002 were on average $0.80 greater than those filed, the futures settlement prices on October 7, 2002 were only on average $0.50 greater than those in the original filing.

related to commodity. Northern states that this under-collection resulted from decreased sales due to one of the warmest winters on record as well as increased stored gas financing costs, as discussed further below. This under-collection is offset somewhat by last winter's lower-than-forecast gas market prices. The reconciliation does not reflect our determinations of the issues discussed below. If approved, the winter 2001 – 2002 under-collection submitted by Northern alone would increase the proposed winter 2002-2003 period cost of gas by approximately $0.0377 cents per ccf for all customer classes.

Maine law allows for the recovery of prior period cost-of-gas under-collections, with interest, during the next corresponding seasonal period. 35-A M.R.S.A. § 4703 and Chapter 430 of the MPUC Rules. The Commission determines the reasonableness of the amounts proposed for inclusion in a cost of gas adjustment, as well as gas supply management prudence, and determines whether recovery of the entire amounts proposed by the Company in CGF rates is warranted.

1. Stored Gas Financing Costs (BayNor Adjustment)

a) Background

Northern uses a financing plan approved by the Commission to finance its gas held in storage. See *Northern Utilities, Inc., Request for Approval of a Gas Purchase Plan with BayNor,* Docket No. 82-100, Order (Dec. 9, 1982) and *Northern Utilities, Inc., Application for Approval of Amendments to Revolving Credit Agreement and Letter of Credit Agreement (§ 902 and § 1101)($12,000,000),* Docket No. 98-845, Order (Dec. 15, 1998). Under the plan, an unaffiliated third party, BayNor Energy, Inc. (BayNor) was established through which Northern's inventory would be financed until such time as needed for use by the customers of Northern. Northern's affiliate Bay State Gas Company has a similar agreement with BayNor and is BayNor's only other customer.

Under the BayNor agreement, Northern sells or transfers the rights to receive title to its fuel inventory to BayNor. BayNor raises the funds necessary to purchase the fuel inventory by the issuance of its own commercial paper. All commercial paper notes issued by BayNor mature less than one year from their respective dates of issue. Union Bank of California provides BayNor with a $37 million irrevocable letter of credit in support of the issuance of BayNor's commercial paper. As a result of this arrangement, the commercial paper issued by BayNor receives an overall higher credit rating and more favorable interest rate than Northern's source of short-term funds.

Northern retains physical control of the gas supply inventories such that when it determines there is a need for amounts of stored gas to send out to its customers, it draws the necessary volumes of gas out of storage to meet its needs. BayNor then invoices Northern for the cost of the volumes withdrawn. The price paid to BayNor for such purchases comprises the cost paid for the fuel and an increment for financing costs and associated fees according to the BayNor contract.

Until Northern withdraws the gas from storage, it does not pay BayNor any interest. The monthly interest is added to the cost of gas stored. Northern pays the management fees to BayNor on a monthly basis. BayNor determines the cost of inventory withdrawn on a per unit basis by dividing total costs it has accumulated by the total volumes Northern has stored and financed by BayNor. This cost is then applied to the volumes withdrawn by Northern to determine the amount to be invoiced.

Northern recently conducted a detailed review of the BayNor process in conjunction with BayNor management. As a result of that review, it was determined that the pricing policies utilized by BayNor were not correct. Rather than maintaining the principal and interest by form of gas (natural, liquefied petroleum (LPG), and liquefied natural (LNG)), BayNor reallocated these dollars by form of gas each month. This resulted in BayNor's records showing a negative investment in LPG, an anomalous result as an accounting matter since if Northern were to utilize LPG, BayNor would have to pay Northern to eliminate that investment.

In addition, the review of the BayNor process brought another issue to Northern's attention. Because Northern only pays interest costs on gas as it is used, any gas remaining in storage continues to accumulate interest until it is actually used. Northern states that all winter supply requirements are filled prior to the upcoming winter seasons to levels that are sufficient to satisfy the projected season's design day winter conditions.[2] Without a design winter, there will be gas that remains in storage until a design winter occurs that will continue to accumulate interest. Northern states that the deferral of interest into future winter seasons (beyond the following winter season in which they are reconciled) does not appropriately assign the cost of providing gas service to the period in which the costs are actually incurred.

In order to address these issues, Northern and BayNor completed a swap-out transaction on March 31, 2002. In this transaction, Northern purchased all the storage gas financed by BayNor on that date. Then Northern sold natural gas storage inventory back to BayNor. As a result of this transaction, all pricing issues were corrected in the accounting records and all interest, current and previously deferred, was billed to Northern. Northern proposes that the full costs of this transaction be included in this winter period's CGF for recovery over the upcoming six months.

b) Proposed Adjustment

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[2] Design day winter conditions are those calculated to represent the utility's highest expected gas usage resulting from a severe weather occurrence of a magnitude only seen, on average, once in approximately 30 years.

Northern's commodity cost reconciliation includes $893,713 of costs related to BayNor. This amount comprises four components: (1) financing costs related to May 2001 to April 2002 ($126,948); (2) financing costs related to May 2000 to April 2001 ($338,780); (3) price differentials between BayNor's and Northern's records ($133,562); and (4) accumulated interest due to gas remaining in storage prior to May 2000 ($294,423).[3]

(1) May 2001 to April 2002 Financing Costs

These are the interest and other costs that Northern has accumulated over the period May 2001 to April 2002 and are a normal part of the cost of gas reconciliation. When Northern made the filing for the winter CGF for 2001-2002, it estimated the costs related to financing its stored gas and included those costs in its cost of gas. The difference between Northern's estimated storage costs and its actual storage costs, like other elements of the CGF rate, are reconciled in the next winter period. Accordingly, winter 2001-2002 costs will be reconciled in the 2002-2003 winter CGF period.

(2) May 2000 to April 2001 Financing Costs

These are the interest and other costs that Northern accumulated over the period May 2000 to April 2002. Northern should have included these amounts in the reconciliation included in its winter CGF filing for 2001-2002. In the reconciliation portion of its filing, Northern stated that BayNor charges were not included in the prior reconciliation because it believed the accounting entries in connection with the BayNor inventory financing arrangement were not clear and it would be reviewing them further to evaluate them. Northern states that it did not accumulate interest on the prior period amounts it omitted from the winter 2001-2002 CGF during the intervening year.

(3) Price Differentials

Northern maintains inventory accounts for each type of gas stored by location. On its accounting books, it accounts for the gas inventory as if it still maintained title. Accordingly, when it either purchases or uses gas, it debits and credits the specific inventory account for the volumes at the average cost of gas for that account. However, BayNor maintains one inventory account and calculates an average blended gas cost for that account. When Northern withdraws gas, it is charged that unit cost of gas. This results in a price differential between what Northern records on its books and what it has paid BayNor. Northern has been deferring this price differential on its books. The "swap-out" transaction discussed earlier eliminated that differential.

[3] These figures come from staff's review and analysis of Northern's responses to Advisor's 1-7 and 2-10.

(4) Accumulated Interest

As discussed earlier, the nature of the BayNor contract leads to the accumulation of interest on gas that remains in storage. The portion of the BayNor adjustment that relates to that interest that has been accumulated over time (prior to May 2000) is $294,423. Although there is no way to determine the actual periods that the interest is related to, a portion of this interest could relate to gas stored as early as the beginning of the BayNor contract in 1982. This raises the question of whether it is reasonable to allow these costs in the upcoming winter CGF rate.

c) Future procedures

Northern plans to complete swap-out transactions at the end of each winter season in future years. By doing so, the interest costs related to financing storage for the just-concluded winter period are charged in that period and not deferred to future periods. To the extent that there is a difference between the estimated costs to finance stored gas included in the CGF and the actual costs incurred, that difference is deferred to the next period where it is included in Northern's normal reconciliation. In addition to properly matching costs to the benefit, Northern states that the procedure will minimize cost distortions. Warm winters that cause storage (as well as LNG and LP) inventories to be held over will not include interest costs that would then flow to the customer in subsequent potentially colder winters seasons that deplete inventory levels.

d) Analysis and Recommendation

In reviewing this item, we must determine whether the BayNor adjustments are reasonable costs for inclusion in the current period CGF and, particularly, whether it is reasonable for Northern to include the entire adjustment – including amounts that could date back to 1982 -- in the current period. The stipulation approved by the Commission in Northern's original request allowed Northern to include BayNor carrying costs of gas inventory in cost of gas rates.

We would allow Northern to include the $126,948 related to the last winter period in its rates because this is a usual cost of its gas supply operation. In addition, we will allow Northern to recover in this upcoming period the amounts it did not include in last winter's reconciliation. We do so recognizing that, while Northern should have submitted the BayNor charges for the previous year for reconciliation in the 2001-2002 winter period, it is not seeking to recover interest for the period of delay.[4] We recognize that unresolved accounting matters prevented Northern from including accurate amounts in that time period.

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[4] We will expect Northern, in the future, to at least apprise us of such omissions at the time they occur, giving an explanation of the reasons for its decision to defer otherwise includable costs in its CGF filings.

The remaining two items (the price deferential and accumulated interest) that make up Northern's total BayNor adjustment require further review and an analysis of current CGF policy to determine whether the costs should be allowed in rates for the upcoming winter period. If Northern had not entered into its "swap-out" transaction, it would have not incurred the cost and therefore, there would be no adjustment to flow through to ratepayers in this winter period. In addition, Northern and its ratepayers would incur no out-of-pocket costs until the gas was used. However, the cost of gas used would increase as BayNor adds the interest to the total cost of gas used to calculate its unit cost, thereby increasing the cost of each unit used.

Alternatively, if Northern had consistently entered into the swap-out transaction each year since the inception of the contract, there would be no deferred interest to flow back currently and presumably the cost to the ratepayer might have been less over the term of the contract. In response to Advisor's Data Request No. 2-6, Northern stated that the transition of the accounting function to the Finance & Accounting Business Service (F&ABS) department in Columbus, Ohio, as well as the build up of interest, prompted the Company to make this swap-out transaction for the first time in March 2002. The accounting function was transferred to Columbus in 2001. F&ABS's review revealed that then-current accounting procedures could result in inordinate deferrals of interest associated with gas remaining in inventory. The combination of warmer-than-normal weather for the past two winters and market conditions, which gave the Company cause to forego withdrawing much of its storage gas this winter, caused high levels of unused inventory gas, and in turn exacerbated the build-up of the associated deferral of interest costs.

In recent years, this Commission has made an effort to put into effect policies to ensure that customers get the appropriate price signals as soon as possible. This involves making sure that all costs are assigned to the proper winter period and that projected commodity costs are calculated as close to the rate period as possible. Charging the customers for whom the stored inventory is purchased for all of the costs related to that stored inventory is consistent with that policy. We note that, given the one-year lag for reconciliation of a prior period's costs and revenues in the next winter season, there cannot be a perfect match between the customers who are charged for these costs and those for whom the costs were incurred. However, we find a one-year lag reasonably matches costs to time period and customers, given these necessary ratemaking circumstances. Therefore, we accept Northern's plan to enter into its "swap-out" transaction as close to the end of the winter cost of gas period as possible each year for reconciliation in the next winter season. If Northern intends to vary from this plan in the future, it should notify the Commission staff of that decision and the reasons for it.

We turn to the question of whether Northern should be allowed to recover costs attributable to this "swap-out" transaction that accrue from the previous 20 years. This determination could depend on whether we decide Northern should have engaged in such "swap-outs" at an earlier point in time or perhaps periodically at intervals of less than 20 years. Moreover, we will explore whether Northern should have engaged in a "swap out" at least at the time it quadrupled the amount of gas it financed through BayNor in 1998.

It is logical to conclude that costs would have been lower in successive years, as well as in total due to the effects of compounding, if Northern had made annual or periodic swap-outs. It is also apparent that the weather and market circumstances of the last few years have magnified the compounding effects resulting from earlier deferred interest treatment, creating a larger dollar impact currently. In years in which market conditions were more stable and withdrawals were more consistent with projected usage – a characterization that we suspect would reasonably apply to earlier years under the BayNor agreement -- deferred interest on remaining storage amounts would be a relatively small concern.[5] Those years represent the period in which Northern financed no more than $3 million through BayNor. Northern increased its financing of stored gas to $12 million in December 1998. The volatility in the gas markets did not begin until the spring of 2000. The combination of increased investment in stored gas with increased volatility in commodity prices shortly thereafter supports Northern's decision to review its financing procedures and to modify those procedures to periodic (annual) swap outs. Northern's experience of the last four years shows it may expect to see greater volatility in both quantity and dollar value of stored gas amounts remaining at season's end. Northern's proposal to swap out remaining balances at season's end will avoid larger compounding effects of carry-over volumes. Therefore, we conclude that Northern acted in an appropriate manner and time frame in changing its policies, and we will allow recovery of the deferred interest amount attributable to the time prior to May 2000. We will also allow recovery of the price differential that occurred due to differences between Northern's and BayNor's inventory system as Northern's policies appear reasonable.

The question remains as to whether to allow the remainder of the BayNor adjustment to be flowed-through currently or amortize it over some period of time. The Company has expressed a willingness to amortize the costs over two years if we so decide. In making our decision here, we look at the overall cost of gas included in this filing. In its initial filing, the bill impact of the filing to the residential customers using the most gas was 4.75%. However, given the anticipated adjustments outlined in this report, it is apparent that the bill impact will be greater due to increases in the cost of gas. This factor, and other costs such as BayNor costs, will be offset to some extent by anticipated reduced rates for transport on the PNGTS system (as discussed later) and recovery of a smaller under-collection included in this period as compared to those included in prior periods. Overall, based upon the gas futures prices

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[5] This is based on our general knowledge that gas market prices have historically been more stable year-to-year than they have in the last 3-4 years. Our premise appears also to be confirmed by the fact that Northern's reported deferred interest for all 28 years prior to May 2000 was about $300,000, or roughly $1,000 per year, whereas the deferred interest costs for 2001-2002 alone are over $300,000.

to date, we do not expect the additional adjustments will increase the bill impact substantially (we estimate approximately 2%) and observe that this is not a material increase compared to past increases.

Since the adjustment related to prior periods causes only a $0.0233 per hundred cubic feet (Ccf) increase in the cost of gas this period, we will allow Northern to include the entire amount in this period. This will also avoid carrying charges that normally accrue on uncollected costs of gas. However, if in calculating its update as directed by this order, Northern determines that the increase caused by all factors together is significantly greater than expected, we would require recovery over a two-year period. In that circumstance, in fairness to ratepayers who are being asked to absorb several years of swap-out costs in one year, we would require that the Company absorb the carrying costs for the portion carried into the second year. This is equitable given that Northern could have acted sooner, foreseeing when it quadrupled its BayNor investment limit that the dollar impact of deferred gas storage costs would likely become a bigger burden each year.

3. <u>Capacity Contract with Granite State Transmission Inc.</u>

Three years ago Northern entered into three supplemental supply contracts to replace supplies originally proposed for the Wells LNG storage facility. *Northern Utilities, Inc., Investigation of Decision to Terminate Agreement with Affiliate, Granite State Gas Transmission Company for LNG Services*, Docket No. 1999-259. Northern recently proposed to enter into an agreement with Granite State, amending its prior contract to increase Northern's capacity on the pipeline by 28,000 MMBtu per day to 112,000 MMBtu for a five-year period at a discounted rate to provide pipeline capacity for the supplemental supply to reach the Northern system. Commission review of this proposal pursuant to 35-A M.R.S.A. §707 is pending in *Northern Utilities, Inc., Request for Approval of Affiliated Interest Transaction for an Amendment to a Gas Transportation Contract with Granite State Gas Transmission, Inc.*, Docket No. 2002-526. Northern's proposed amended contract with Granite requires affiliated transaction review and approval by this Commission before it may take effect. Northern filed its proposed contract on August 30, 2002 and requested review and approval to allow the amended contract to take effect on November 1, 2002, at the beginning of the winter CGF rate season. However, on October 2, 2002, Northern requested suspension of the procedural schedule to allow it to reevaluate its filing. The Company may seek to withdraw the proposed contract and to submit a different arrangement for the upcoming winter season.

Northern did not include the full cost of its proposed contract with Granite in this CGF filing. In the technical conference, Northern indicated that it planned to include these costs in when it makes its updated filing. The increased capacity at the lower rate increases Northern's costs approximately $275,000 per year.

Given the current uncertainty regarding the Granite capacity and cost that will ultimately be approved for the upcoming winter season, Northern should calculate its updated filing to include only costs related to the currently approved Granite contract. The CGF is fully reconcilable and any increased costs would be recovered by Northern in its next contract. If the increase in the cost combined with any changes in the cost of gas becomes significant, Northern could also make a mid-course correction.

4. Allocation of Costs Between Divisions

In the September 24, 2002, technical conference, Northern indicated that through discussions with the staff of the New Hampshire Public Utilities Commission it discovered an error in allocating costs between the Maine and New Hampshire divisions. In preparing the filing, Northern designated projected costs associated with the capacity at the MichCon (MCN) storage facility for May 2002 to April 2003 period as a year-round cost instead of a winter period cost. The result is that Maine's allocation percentage was erroneously calculated as 48.36% instead of 49.16%, undercharging the Maine division. Northern would have overcharged its New Hampshire division an equivalent amount but discovered its error prior to making its New Hampshire cost of gas filing. Northern proposes to correct the allocation to Maine for the upcoming winter period in its updated filing later this month. Based upon these discussions, we concur that the costs related to the MCN storage are related to the winter period and should be allocated between Maine and New Hampshire in the manner Northern proposes. Therefore, we permit Northern to make this adjustment in its updated filing.[6]

5. PNGTS Capacity Costs

Northern has contracted for a substantial amount of its necessary pipeline capacity on the Portland Natural Gas Transmission System (PNGTS) transmission pipeline. The majority of the costs related to this capacity are included in the winter filing. PNGTS has filed for a rate increase with the Federal Energy Regulatory Commission (FERC) and parties are currently negotiating a settlement. In its proposed cost of gas filing, Northern included its PNGTS costs at the interim rate accommodation level of $0.95/Dth currently in effect. However, it appears that the parties are close to reaching a settlement that would produce a rate less than the interim rate accommodation, although that settlement would require FERC approval and the timing of such approval is uncertain.

PNGTS rates are currently approved subject to refund and as such Northern would be reimbursed by PNGTS for any payments made above the finally approved rate. Therefore, it is reasonable for Northern to adjust its filing to reflect the

[6] We accept a change to the current filing affecting the prospective CGF rate. Northern should not assume that our approval of this correction here reflects the position we may take if considering whether Northern should be allowed to recover any changes attributable to its error in past periods.

rate closest to the settlement rate in its current CGF rate if it is confident that that rate best predicts the costs Northern expects to pay for capacity during the upcoming winter period, although we will not require it to do so. Northern's costs related to PNGTS, like all other prudently incurred cost of gas costs, are subject to reconciliation to actual amounts in the CGF.

6. Environmental Recovery Cost Adjustment

Northern has proposed an ERC rate of $0.0062 for the 2002 – 2003 winter period. As required by the settlement in Docket No. 96-678, Northern filed copies of the invoices supporting the costs incurred during July 2001 to June 2002. The staff have reviewed the invoices and determined that the costs are recoverable in accordance with the settlement agreement. Therefore, we approve the ERC as filed.

IV. CONCLUSION

We recommend that Northern make a revised CGF filing that reflects the decisions outlined above. In addition, we delegate to the Director of Technical Analysis, authority to review and approve Northern’s revised filing based on its consistency with this order.

Dated at Augusta, Maine, this 22nd day of October, 2002.

BY ORDER OF THE COMMISSION

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Dennis L. Keschl
Administrative Director

COMMISSIONERS VOTING FOR: Welch
Nugent
Diamond

NOTICE OF RIGHTS TO REVIEW OR APPEAL

5 M.R.S.A. § 9061 requires the Public Utilities Commission to give each party to an adjudicatory proceeding written notice of the party's rights to review or appeal of its decision made at the conclusion of the adjudicatory proceeding. The methods of review or appeal of PUC decisions at the conclusion of an adjudicatory proceeding are as follows:

1. Reconsideration of the Commission's Order may be requested under Section 1004 of the Commission's Rules of Practice and Procedure (65-407 C.M.R.110) within 20 days of the date of the Order by filing a petition with the Commission stating the grounds upon which reconsideration is sought.

2. Appeal of a final decision of the Commission may be taken to the Law Court by filing, within **21 days** of the date of the Order, a Notice of Appeal with the Administrative Director of the Commission, pursuant to 35-A M.R.S.A. § 1320(1)-(4) and the Maine Rules of Appellate Procedure.

3. Additional court review of constitutional issues or issues involving the justness or reasonableness of rates may be had by the filing of an appeal with the Law Court, pursuant to 35-A M.R.S.A. § 1320(5).

Note: The attachment of this Notice to a document does not indicate the Commission's view that the particular document may be subject to review or appeal. Similarly, the failure of the Commission to attach a copy of this Notice to a document does not indicate the Commission's view that the document is not subject to review or appeal.